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CO_2 storage in saline aquifers II – experience from existing storage operations

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Abstract

The Intergovernmental Panel of Climate Change Special Report on Carbon Capture and Storage in 2005 identified various knowledge gaps that need to be resolved before the large-scale implementation of CO_2 geological storage is possible. The experience from CO_2 injection at pilot projects (Frio, Ketzin, Nagaoka) and existing commercial operations (Sleipner, Snøhvit, In Salah, acid-gas injection) demonstrates that CO_2 geological storage in saline aquifers is technologically feasible. By the end of 2007, approximately 15 Mt of CO_2 had been successfully injected into saline aquifers by these operations. However, these projects are not necessarily representative of conditions encountered globally. A larger portfolio of large-scale storage operations is needed to provide data for verification and calibration of numerical models, to better constrain geomechanical as well as geochemical processes, and to optimize monitoring and verification plans for different storage settings.

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Keywords: CO_2 geological storage; saline aquifers;

1. Introduction

Injecting carbon dioxide (CO_2) into deep saline aquifers is one of three main options for the geological storage of CO_2 in order to reduce anthropogenic greenhouse gas emissions into the atmosphere. Previous studies have shown that, compared to the other two major options (storage in depleted hydrocarbon reservoirs and in deep, un-mineable coal seams), deep saline aquifers have the highest potential capacity globally for CO_2 storage. The Special Report on CO_2 Capture and Storage by the IPCC [1] identified various knowledge gaps related to aquifer storage of CO_2, many of which needed addressing before the widespread commercial implementation of the technology is possible. Yet,

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there are a few existing operations that have been successfully injecting CO_2 into saline aquifers (Figure 1). Consequently, the IEA GHG instigated a study to review the recent advancements in the science related to aquifer storage of CO_2, to compile the knowledge gained from existing CO_2 injection operations and to address the need for future research. A companion paper, "CO_2 Storage in Aquifers I – Current State of Knowledge", reviews the main knowledge gaps with respect to the actual science of CO_2 storage in saline aquifers identified in the IPCC SRCCS, which includes the geochemical processes in the subsurface environment, the numerical modeling of coupled processes, new developments and methodologies with respect to Storage Capacity Estimations, Best Practice of Site Characterisation and Risk Assessment related to the geological storage of CO_2 in saline aquifers. This paper reviews the experience gained from pilot and demonstration projects, including:

1. A detailed examination of data from existing saline aquifer storage sites and pilot projects; provision of a database of available reservoir properties (e.g., lithology, porosity, permeability, injectivity, brine chemistry) to help establish whether current storage operations cover a representative range of reservoir characteristics and/or if specific aquifer types should be targeted with future pilot sites or demonstration projects;
2. A comparison and assessment of monitoring technologies applied at the various operations; and
3. A description of the various regulatory regimes under which the current projects operate and a compilation of economics, to the extent to which this is possible.

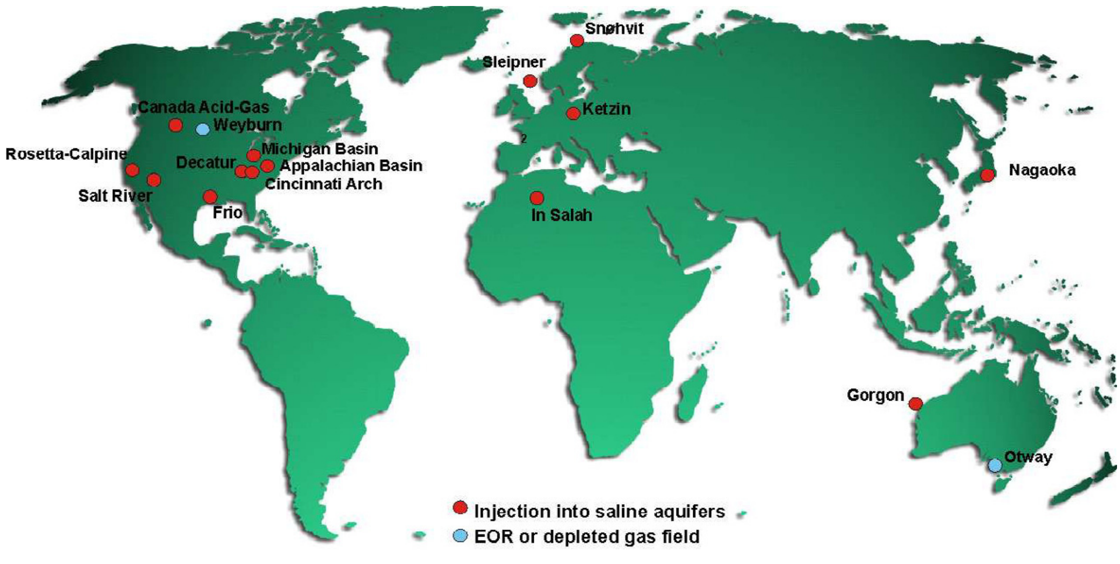

Figure 1. Map showing projects injecting or having injected CO_2 into deep saline aquifers. Also shown are projects in an advanced planning stage (see text for details) as well as the Weyburn and Otway pilot projects.

2. Results

The first operations injecting CO_2 into saline aquifers in the early 1990's were acid-gas (H_2S and CO_2) disposal projects in Canada (Figure 2), driven by the need to reduce flaring of H_2S from sour gas wells and CO_2 being an additional unwanted by-product [2,3]. The first commercial-scale project with the sole purpose of disposing of CO_2 from gas production started in 1996 at Sleipner in the Norwegian sector of the North Sea [4]. In Salah in Algeria [5] and Snøhvit in Norway [6], both injecting CO_2 from natural gas production, commenced operations in 2004 and 2008, respectively. Various commercial projects are planned for the future, with Gorgon in Australia, another natural gas facility, anticipated to start injecting in 2009, potentially becoming the largest CO_2 storage operation in the world [7]. Pilot injection operations for research purposes were run in Nagaoka (Japan) [8] and Frio (USA) [9] between 2003 and 2005. New pilot operations in Ketzin (Germany) [10], Otway (Australia) [11] and selected projects in the US DOE Regional Carbon Storage Partnership (RCSP) program started injection in 2008, with more projects in the RCSP planning to commence in 2009 (www.fossil.energy.gov/sequestration/partnerships/index.html). Details of aforementioned operations publically available in the literature and on company websites were compiled in a database and summarised in Tables 1 and 2.

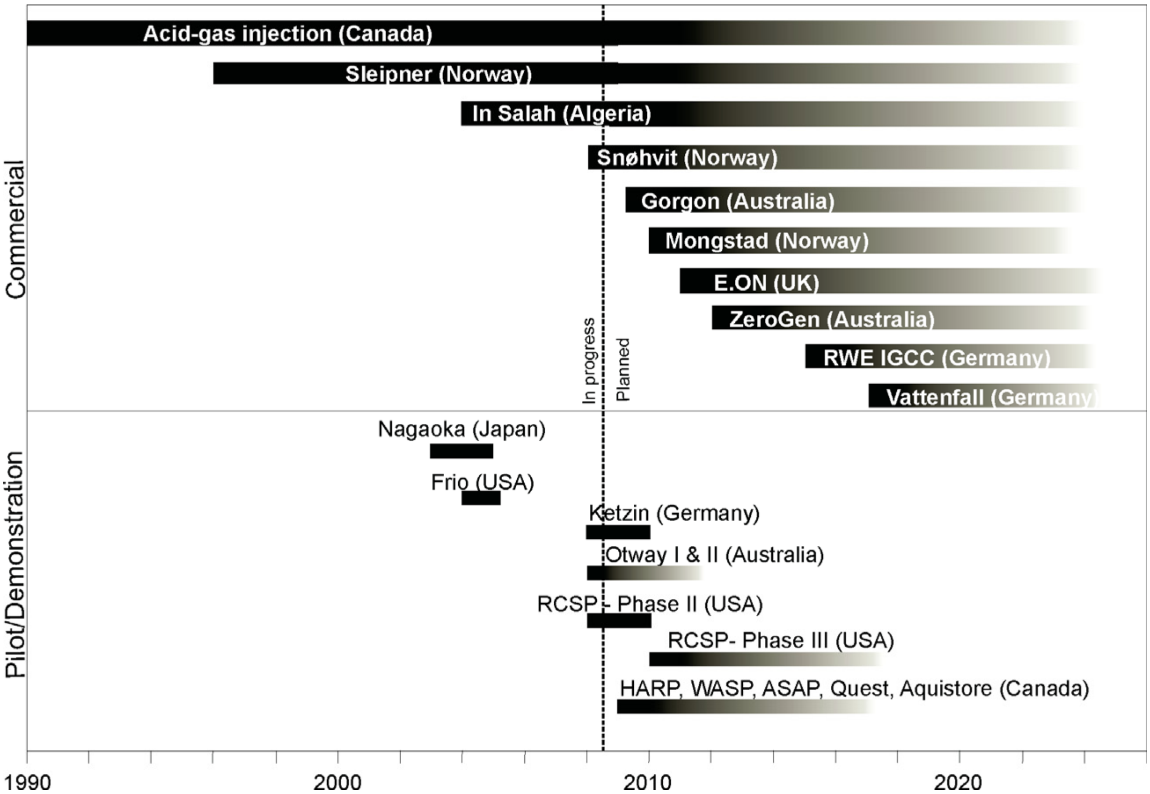

Figure 2. Past and future implementation of CO_2 geological storage in saline aquifers.

2.1. Operational and reservoir characteristics

By the end of 2007, approximately 15 Mt of CO_2 had been successfully injected into saline aquifers by commercial operations. Particularly, Sleipner, In Salah, and Snøhvit demonstrate that, given the right geological and reservoir conditions, injecting industrial-scale volumes in the order of 1 Mt/year CO_2 into saline aquifers is achievable. However, these projects are not necessarily representative of conditions encountered globally. For example, aquifer permeability at Sleipner is probably unusually high compared to what could be expected for other sites. In Salah operates 3 injection wells in a low-permeability aquifer, but there is limited monitoring information. Nagaoka and Frio have comprehensive monitoring and verification (M&V) programs, but injection rates/volumes are very low. The various acid-gas injection operations in Alberta cover a wide range of reservoir properties, but again injection rates are relatively low and very limited subsurface monitoring is done. The majority of existing operations inject into siliciclastic reservoirs with the exception of various acid-gas injection sites and the Michigan Basin in the RCSP.

2.2. Monitoring and verification

With respect to monitoring and verification of CO_2 storage reservoirs, 4D seismic proved to be very successful at Sleipner [12], but has the disadvantage of being relatively expensive and might prove challenging for onshore storage sites related to repeatability problems due to changing weather, soil humidity and contact conditions. Also, successfully implemented at Sleipner was 4D gravity [12, 13], which has lower costs and works well for qualitative assessment of CO_2 saturation in the subsurface, but requires a detailed, well-characterised geological model. Promising geophysical methods that worked well at Frio and Nagaoka for quantitative tracking of the CO_2 plume was 4D vertical seismic profiling (VSP) [14,15], which allows for a good source signal control, and cross-well electro-magnetics. However, these two methods require a monitoring well in addition to the injector. Also, the transmission distance between injection and monitoring well might get too big in the case of commercial projects with large CO_2 plume sizes, resulting in a loss of resolution unless multiple monitoring wells at appropriate distances were installed. Tracer technology has been successfully tested at the Frio and Otway pilot projects [16, 17]. Monitoring technologies for the shallow groundwater, soil and atmosphere have been developed, however they have not yet been successfully demonstrated to detect potential CO_2 leaks from the reservoir unit due to relatively high natural CO_2 fluctuations in these environments. Requisite monitoring plans in future regulations for CO_2 storage projects should carefully weigh the necessary requirements for ensuring storage verification and safety against cost and suitability of various monitoring techniques for specific storage environments.

2.3. Regulations and economics

Regulations are currently in place in various countries under which commercial (Sleipner, Snohvit, acid gas) and pilot projects (Nagaoka, Frio, Ketzin) were approved, but mainly done under petroleum legislation. Key issues that have to be addressed better in regulations currently under development are:

1. Long-term liability/stewardship for storage sites (post-injection);
2. Definition of M&V requirements;
3. Emission Trading Scheme (ETS) implications, especially regarding the treatment of CCS permits;
4. Resolution of conflict of interests (effect of storage on other resources);
5. Definition of key performance indicators; and
6. Royalties/lease fees for storage space.

Comparing the costs for operations storing CO_2 in saline aquifer is difficult for a variety of reasons: a) cost data are scattered and patchy; b) costs are quoted for different years, c) costs are quoted in different currencies, and d) quoted costs are based on different methodologies. As a result, considerable analysis would be required to normalise the cost data and construct predictive analytical tools for future projects. Alternatively, although not mutually exclusive, computerised costing models and equations could be created, based on vendor quotes that reflect current economic circumstances.

Table 1. List of operations injecting or having injected CO_2 in saline aquifers. Some projects in an advanced planning stage are also shown.

ProjectID	Name	Location	Type	Status	Scale	Project Start Year	Injection Start Year	Injection Finish Year	Total Storage (kt)
69	In Salah	Krechba, Algeria	Saline Aquifer	Injection Underway	Commercial		2004		17000
75	Nagaoka	Nagaoka City, Japan	Saline Aquifer	Completed	Micro Pilot Test Pr	2000	2003	2005	10.4
80	Ketzin	Ketzin, Brandenburg, Germany	Saline Aquifer	Injection Underway	Pilot	2007	2008	2010	60
86	Sleipner	Sleipner Field, North Sea	Saline Aquifer	Injection Underway	Commercial		1996		20000
87	Snøhvit	NE of Hammerfest, Barents Sea	Saline Aquifer	Injection Underway	Commercial		2008		23000
91	Alberta Basin (Acid Gas)	Alberta, Canada	Saline Aquifer	Injection Underway	Commercial	1989	1990		
99	Frio	Liberty County, Texas, USA	Saline Aquifer	Monitoring Underway	Pilot	2002	2004	2004	1.6
130	MGSC Decatur	Decatur, Illinois, USA	Saline Aquifer	Planned	Demonstration	2008	2009	2012	1000
134	MRCSP - Cincinnatti Arch	Duke Energy East Bend facility, Kentucky, USA	Saline Aquifer	Planned	Pilot	2008	2009		3
129	MRCSP Appalachian Basin	Shadyside, Ohio, USA	Saline Aquifer	Work Underway	Pilot		2008		3
128	MRCSP Michigan Basin	Gaylord, Michigan, USA	Saline Aquifer	Monitoring Underway	Pilot		2008	2008	10.241
131	WESTCARB Rosetta-Calpine Saline	Rio Vista, California, USA	Saline Aquifer	Planned	Micro Pilot Test Pr	2007	2009	2009	2
104	WESTCARB Salt River	Northeast Arizona, USA	Saline Aquifer	Planned	Micro Pilot Test Pr	2007	2009	2009	2
114	Gorgon	Barrow Island, WA, Australia	Saline Aquifer	Planned	Commercial		2009		129000

Table 2. Comparison of reservoir characteristics of injection operation in saline aquifers.

Project Name	Location	Inj. Rate (t/d)	Injection Unit	Lithology	Depth (m)	Thickness (m)	Net Pay (m)	Porosity (%)	Perm. (mD)	Seal Lithology	Thickness (m)	Trap Mechanism	TDS (mg/l)	Temp (C)	Pressure (kPa)
In Salah	Krechba, Algeria	3500	Krechba Formation	Sandstone	1850	29			5	Mudstone	950				
Nagaoka	Nagaoka City, Japan	40	Haizume Formation	Sandstone	1100	60	12		6	Mudstone	133	closed anticline	7113	46	11900
Ketzin	Ketzin, Brandenburg, Germany	86	Suttgart Fm.	Sandstone	650	80		23	750	Mudstone With Dolomite Beds	210	Structural - anticline	250000	34	7300
Sleipner	Sleipner Field, North Sea	2700	Utsira Formation	Sandstone	1000	250	90	37	5000	Shale	75	Structural - Anticline	35000	37	10300
Snøhvit	NE of Hammerfest, Barents Sea	2000	Tubåsen Formation	Sandstone	2550	60	50	13	450	Shale	30	Structural trap			28500
Alberta Basin (Acid Gas)	Alberta, Canada 27 operations	5-190	Various	Various	950-2814	15-343	4-100	4-26	1-413	Various	15-218	Various	23,750 -340,000	26-103	6,000 -27,000
Frio	Liberty County, Texas, USA	160	Upper Frio C	Sandstone	1546	24	7	30	1500	Shale	78	Tilting Horizon	92633.3	56	15200
MGSC Decatur	Decatur, Illinois, USA	1000	Mt. Simon Sandstone	Quartzose Sandstone	1980	300		15	225	Shale	100		120000		15000
MRCSP - Cincinnatti Arch	Duke Energy East Bend facility, Kentucky, USA	100	Mt. Simon Sandstone	Sandstone	1000	100				Shale	1500				
MRCSP Appalachian Basin	Shadyside, Ohio, USA	75	Clinton Sandstone	Sandstone	2170	78				Limestone	70				
MRCSP Michigan Basin	Gaylord, Michigan, USA	500	Bass Islands Dolomite/Bois Blanc	Dolomite	1061	22		21	22	Limestone	76			28	13858
WESTCARB Rosetta-Calpine Saline	Rio Vista, California, USA		McCormick sand	Sandstone	1052					Shale					
WESTCARB Salt River	Northeast Arizona, USA		Martin Formation	Quartzose Sandstone	1081	200		15		Shale	620	lithological			
Gorgon	Barrow Island, WA, Australia	10000	Dupuy Formation	Massive Sandstone	2300			20	25	Shale	250	open anticline	7000	100	22000

3. Conclusions

The experience from CO_2 injection at pilot projects (Frio, Ketzin, Nagaoka) and existing commercial operations (Sleipner, Snøhvit, In Salah, acid-gas injection) shows that CO_2 geological storage in saline aquifers is technologically feasible. These operations have been extremely helpful for testing monitoring and verification technology and have been used to establish best practice guidelines (i.e., Chadwick et al. [13]) for future CO_2 geological storage sites. However, some issues remain:

1. Pilot sites generally have a comprehensive monitoring program, but injection rates/volumes are low compared to potential commercial projects;
2. Existing commercial projects inject considerable volumes of CO_2, however monitoring programs are often limited (i.e., In Salah, Alberta acid-gas) or reservoir properties are "unrepresentatively good" (i.e., relatively high permeability at Sleipner);
3. Still need to "prove" that migration outside the storage container can be detected and need to develop better methodologies for seismic imaging of CO_2; and
4. Testing of new, cost-effective methods.

Hence, there remains the need for a more comprehensive portfolio of saline aquifer storage projects that covers the range of variability of different subsurface environments (e.g., on-/offshore, low/high permeability, sandstone/carbonate/basalt, pressure, temperature, and salinity) as well as different monitoring strategies, regulation requirements and economics. The funding by the US DOE of a variety of small to large-scale injection projects in the various Regional Partnerships is a promising step towards gathering experience for different storage scenarios. However, it is interesting to note that in North America, all operations inject onshore and, with the exception of the Michigan Basin project, into sandstone aquifers.

It is important to properly integrate the lessons learned from existing storage projects in the regulatory frameworks that are currently being developed in many countries. Particularly when establishing guidelines for monitoring and verification, a reasonable balance has to be found between assuring safety of the storage operation and the costs of the M&V system. The applicability of various monitoring techniques and the necessity for monitoring wells, which would significantly add to the project costs, will have to be assessed on a case by case basis for different storage environments.

It is worth mentioning that the expertise in CO_2 injection technology currently resides mainly with the petroleum industry and other industries need to be introduced and, maybe more importantly, become more comfortable with the concept of geological storage. The first commercial implementations of CCS from coal-fired power plants are expected to commence in 2011 (E.ON, UK) and in 2012 (ZeroGen, Australia) (Figure 2).

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